Alberta PETROLEUM MARKETING COMMISSION

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October 15, 1985

The Honourable E.P. Lougheed, Premier
and
The Honourable John Zaozirny, Minister
Government of the Province of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B7

Gentlemen,

In accordance with the provisions of the Petroleum Marketing Act and the Natural Gas Pricing Agreement Act, the Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1984. I have the pleasure to submit the 1984 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,

D. A. Lucas
Chairman

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Calgary circa 1932, Myrtle Jackson, b.1914. Calgary has changed dramatically since this downtown view was taken from the north side of the Bow River, overlooking the Centre St. Bridge.
Courtesy of Glenbow-Alberta Institute.

MYRTLE JACKSON

FOREWORD

1984 marked the end of an era for the Alberta Petroleum Marketing Commission. While the Commission's range of responsibilities has changed a number of times since its inception in late 1973, 1984 marked the last full year in which the Commission will market crude oil in a regulated environment.

As the year drew to a close, the stage had been set for a new federal/provincial agreement to deregulate the marketing of crude oil and natural gas. Only the timing and the extent of the deregulation remained to be determined.

As this annual report goes to press, oil deregulation is behind us and work continues to define the extent to which natural gas will also be deregulated.

This transition could not have occurred at a more challenging time.

Petroleum, traditionally sold internationally on a tightly controlled supply basis has rapidly become a commodity, like any other, subject to price cycles. Currently it is in great surplus and subject to strong downward pressure on price.

While the nature of natural gas deregulation in Canada has not yet been established, 1984 saw the implementation of market pricing arrangements for natural gas exports into United States markets. These exports constitute roughly one-third of Alberta sales. Indigenous natural gas supplies in the U.S. currently exceed demand and U.S. political currents favour deregulation of the natural gas industry. This has increased pressure on the downward movement of U.S. gas prices. It is in this environment that Alberta must continue to sell its export gas.

Accordingly, the challenge for all sellers of Alberta oil and natural gas, at least during the near future, will be to maximize revenues while selling into a buyer's market characterized by a surplus of supply.

PETROLEUM

FUNCTIONS AND RESPONSIBILITIES

The Petroleum Marketing Act created the Commission as agent to sell the Crown's royalty share and lessee's share of petroleum and pentanes plus from Crown leases. The Commission administers the Act through procedures that include the following:

- issuance of price bulletins in which the Commission prescribes selling prices for petroleum and pentanes plus;
- designation of operators to make deliveries of petroleum and pentanes plus from Crown leases to the Commission;
- movement of petroleum and pentanes plus from point of receipt to buyers at point of sale;
- sale of petroleum and pentanes plus by the Commission to buyers;
- remittance of proceeds of sale of the lessee's share to designated operators for distribution to owners;
- remittance of proceeds of sale of the Crown's royalty share to the Provincial Treasurer.

The Memorandum of Agreement of September 1, 1981 between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation (the Canada-Alberta agreement) established higher prices (NORP) for 'new' oil, effective January 1, 1982 and 'new' pentanes plus and bitumen effective April 1, 1982. Oil and pentanes plus eligible for 'new' status are those discovered after December 31, 1980. The National Energy Program Update of May, 1982 established, as of July 1, 1982, a special old oil price (SOOP) for oil discovered between April 1, 1974 and December 31, 1980. Pentanes plus discovered between January 1, 1974 and December 31, 1980 also became eligible for SOOP. As a result of a June 30, 1983 amendment to the Canada-Alberta agreement, oil and pentanes plus eligible for SOOP prices received NORP prices effective July 1, 1983.

The Commission pays operators for all petroleum and pentanes plus at the conventional old oil or NORP prices. Sales are made to buyers at conventional old oil prices plus applicable pipeline transportation costs to the point of sale. The funds to cover the difference between the conventional old oil price and the NORP price is paid to the Commission by the federal government.

In addition to marketing Crown lease petroleum, pentanes plus and bitumen, the Commission also purchases and markets these substances produced from certain lands other than Alberta Crown lands, under private contracts with producers.

SALES

During the year the Commission sold 58.9 million cubic metres of petroleum, pentanes plus and bitumen from Crown and freehold lands. These sales, together with NORP and SOOP supplements totalling $1.5 billion, realized total revenues of $12.6 billion. Of that amount, 51.7 million cubic metres from Crown lands were sold for $10.9 billion. The Crown royalty share totalled 15.8 million cubic metres, valued at $3.3 billion.

Monthly average volumes of sales from Crown leases are shown in Figure 1, with the value of those sales shown in Figure 2.

FIGURE 1
MONTHLY AVERAGE SALES VOLUMES FROM CROWN LEASES

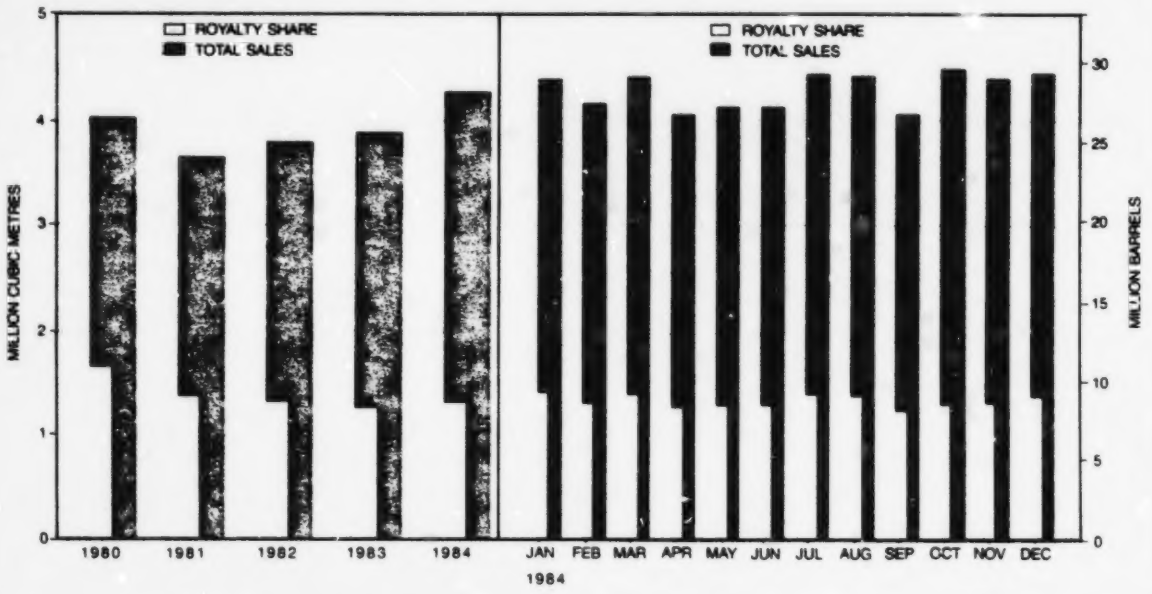
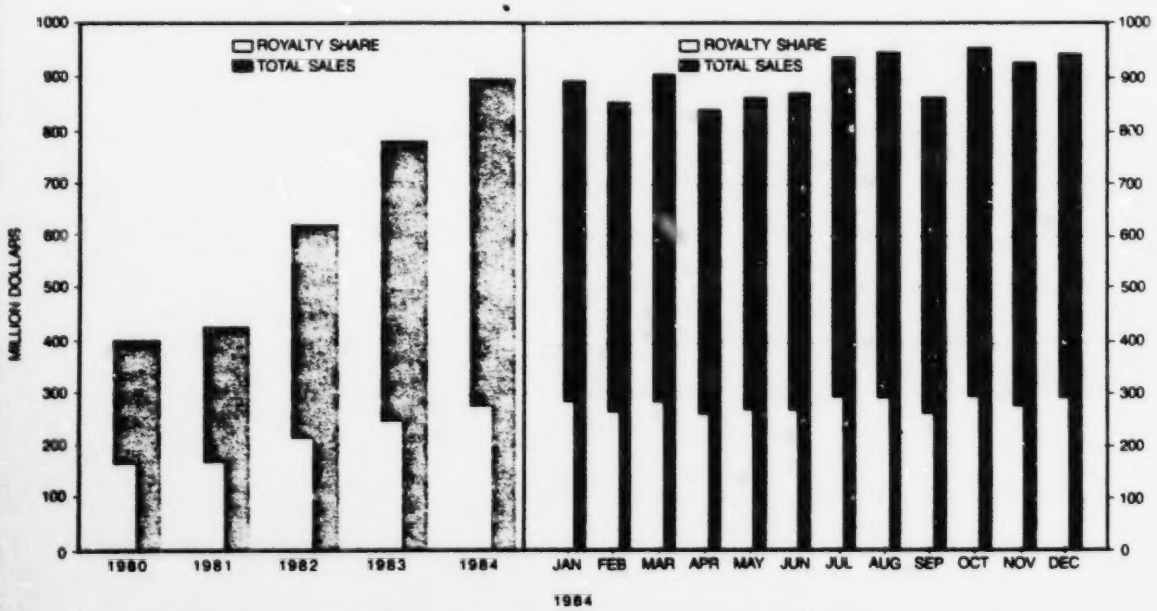


FIGURE 2
MONTHLY AVERAGE SALES VALUES FROM CROWN LEASES



PRICING

The price bulletins issued by the Commission prescribe the prices for petroleum, pentanes plus and bitumen marketed by the Commission, incorporating variations in quality based on density and sulphur content.

Posted field prices during the year for petroleum with a density of 825 to 844 kilograms per cubic metre and a sulphur content of 2.5 to 4.9 grams per kilogram are shown in Table 1.

TABLE 1

FIELD PRICE

($/cubic metre)

1984	Old Oil	NORP Oil
January	187.75	242.05
February	187.75	242.05
March	187.75	242.05
April	187.75	247.70
May	187.75	248.50
June	187.75	253.00
July	187.75	254.15
August	187.75	258.30
September	187.75	254.90
October	187.75	257.00
November	187.75	255.20
December	187.75	252.60

NORP prices are established by the federal government based on the cost of a basket of international crudes landed at Montreal.

Old oil field prices are maintained at an average field price as specified in the Canada-Alberta agreement. The January 1, 1983 price remained effective throughout 1984.

Table 2 shows the average old oil field prices for conventional crude oil for the period from July 1, 1979 to January 1, 1983.

TABLE 2

AVERAGE OLD OIL FIELD PRICE

Effective Date	$ Barrel	$ Cubic Metre
Jul. 1, 1979	13.75	86.53
Jan. 1, 1980	14.75	92.83
Aug. 1, 1980	16.75	105.40
Jan. 1, 1981	17.75	111.70
Jul. 1, 1981	18.75	117.99
Oct. 1, 1981	21.25	133.72
Jan. 1, 1982	23.50	147.88
Jul. 1, 1982	25.75	162.04
Jan. 1, 1983	29.75	187.21

NATURAL GAS

FUNCTIONS AND RESPONSIBILITIES

The Natural Gas Pricing Agreement Act governs field prices of natural gas production in Alberta and implements the 1981 Canada-Alberta agreement on natural gas pricing.

The functions and responsibilities of the Commission with respect to the Act are as follows:

- determination of Alberta costs of service for original buyers;
- purchase of gas and its subsequent resale;
- administration of the Natural Gas Pricing Agreement Act Fund (the Fund) comprised of revenues derived from gas exports to the United States;
- determination of a price adjustment to be paid each month to producers with respect to eligible gas;
- reimbursement or payment of a price adjustment from revenues in the Fund;
- determination and payment of market development incentive payments to the federal government from the Fund;
- administration of the Natural Gas Pricing Agreement Market Development Fund (the Market Development Fund) comprised of revenues derived from the Market Development Levy;
- determination and collection of a Market Development Levy assessed against all gas intended to be removed from Alberta;
- determination and payment, from the Market Development Fund, of incentives to natural gas distributors under the Natural Gas Markets Incentive Plan.

PRICING

Under the Act the monthly regulated field price for natural gas purchased by original buyers that remove gas from Alberta is: Alberta Border Price *less* Alberta Cost of Service *plus* Price Adjustment.

Natural gas purchased for consumption within Alberta is required to be priced as described above or at the contract field price specified in a natural gas sales contract plus a price adjustment, whichever is the lesser. Figure 3 shows average regulated field prices during the past five years.

The Canada-Alberta agreement on natural gas pricing covering the period November 1, 1981, to January 31, 1987 established an initial Alberta border price of $1.701 62 per gigajoule and provided for subsequent increases of approximately $0.23 per gigajoule every six months during the term of the agreement. On June 30, 1983 an amendment was made which provides that, during the 18 month period commencing August 1, 1983, natural gas prices at the Alberta border would be determined on the basis of 65 percent of the price of domestic crude oil at Toronto, less transportation cost from the Alberta border to the eastern zone and federal charges. The calculation of the border price is conditional upon the federal government reducing the Natural Gas and Gas Liquids Tax as needed to accommodate increases in the Alberta border price as specified in the agreement. This tax was reduced to zero in February, 1984. Further increases in transmission tolls to eastern Canada greater than five percent of tolls in effect at June 30, 1983 would be absorbed by the federal government.

Table 3 shows a history of the Toronto city gate price transportation cost from Alberta to Toronto and Alberta border price.

TABLE 3
HISTORY OF NATURAL GAS PRICES AND TRANSPORTATION COSTS
($/gigajoule)

Date	Toronto City Gate Price(1)	Alberta - Toronto Transportation Cost	Alberta Border Price
Jan 1, 1980	2 003 86	0 590 89	1 412 97
Feb 1, 1980	2 143 67	0 602 61	1 541 06
Sep 1 1980	2 423 28	0 629 20	1 794 08
Nov 1 1980	2 423 28	0 647 63	1 775 65(2)
Sep 1 1981	2 423 28	0 721 66	1 701 62(2)(3)
Feb 1 1982	2 683 90	0 749 27	1 934 63
Aug 1 1982	2 931 83	0 764 19	2 167 64
Sep 1, 1982	3 047 59	0 879 95	2 167 64
Feb 1 1983	3 284 10	0 883 45	2 400 65
Aug 1 1983	3 570 67	0 937 01	2 633 66
Feb 1, 1984	3 717 63	0 927 62(4)	2 790 01
Aug 1 1984	3 725 66	0 927 62(4)	2 798 04

(1) Does not include federal excise taxes
(2) Established by the Government of Canada pursuant to the Petroleum Administration Act
(3) Alberta border price confirmed by the Canada-Alberta agreement effective November 1 1981
(4) In determining the Alberta border price, the federal government agreed to subsidize the eastern zone contract demand toll of TransCanada PipeLines Limited if it is greater than 105 percent of the June, 1983 toll

PRICE ADJUSTMENT

Substantially all natural gas acquired by original buyers in Alberta is purchased by the Commission. Gas destined for the Canadian market is sold back to the original buyer at the purchase price. Gas destined for export to the United States is resold to the original buyer at the export price less transmission costs. The proceeds resulting from these buy/sell transactions for export gas constitute the Fund from which price adjustment and market development incentive payments are made.

The quantities and destinations of gas sold by the Commission are shown in Figure 4.

The Commission calculates a price adjustment each month based on proceeds available in the Fund and estimated quantities of natural gas produced for market. Alberta producers receive a monthly price adjustment for all eligible deliveries either through the regulated field price paid by an original buyer or, in some circumstances, by claiming directly from the Fund. Original buyers are reimbursed from the Fund for price adjustments paid to producers through the regulated field price.

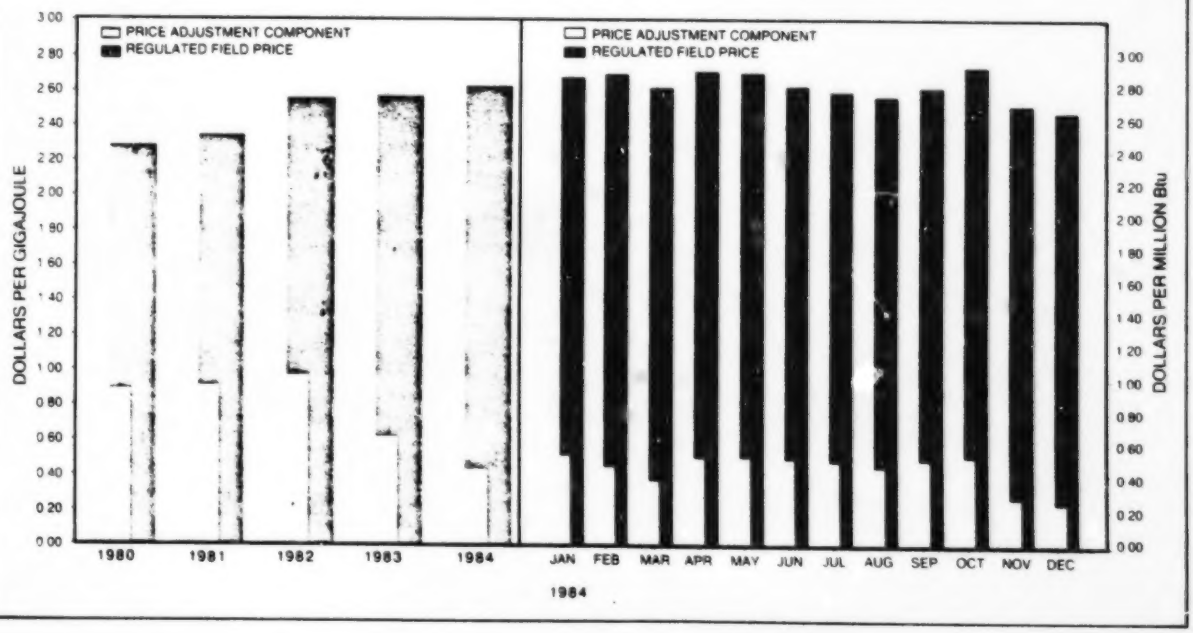
During the year the Commission purchased 2 465 petajoules of natural gas, for which it paid $5.5 billion and sold for $6.6 billion, resulting in proceeds to the Fund of $1.1 billion. Total natural gas production for market was 2 552 petajoules, on which a price adjustment averaging $0.41 per gigajoule was paid from Fund proceeds.

Prices for natural gas exported to the United States since January 1, 1980 are shown in Table 4.

The price adjustment expressed in dollars per gigajoule set by the Commission during the year was as follows:

January	0.50	July	0.45
February	0.43	August	0.42
March	0.35	September	0.46
April	0.48	October	0.48
May	0.48	November	0.24
June	0.47	December	0.21

FIGURE 3
REGULATED FIELD PRICE FOR NATURAL GAS



Effective November 1, 1984, the federal natural gas export pricing policy was changed from an administered system to one which permits Canadian exporters to negotiate prices with their United States customers. The new policy has resulted in increased export volumes but at lower export prices under those contracts which have been renegotiated. The effect has been a decline in the unit price adjustment paid, for the months of November and December 1984.

TABLE 4

NATURAL GAS EXPORT PRICES
($U.S./gigajoule)

	Export Price(1)
Jan. 1, 1980	3.220 00
Feb. 17, 1980	4.170 00
Apr. 1, 1981	4.600 00
Apr. 11, 1983(2)	4.100 00
Nov. 1, 1984(3)	3.051 34

(1) Except for minor quantities exported at Fort Frances.
(2) On July 6, 1983 a Volume Related Incentive Pricing Plan was introduced, providing for a reduced price of $3.17 U.S. applicable to export sales in excess of a specified minimum quantity.
(3) Effective November 1, 1984, natural gas exporters were authorized to negotiate export prices with their buyers subject to approval by the federal government. The price shown is the weighted average price for all gas exported in November and December, 1984.

MARKET DEVELOPMENT INCENTIVE PAYMENTS

In order to encourage expansion of markets for Alberta-produced natural gas in provinces east of Alberta, the Canada-Alberta agreement provides for market development incentive payments to be made by the Commission to the federal government. These payments, which amounted to $75 million for the 12 months ending January 31, 1985, are to be used to subsidize the expansion of natural gas transmission and distribution facilities and for sales promotion programs. On November 2, 1984 an amendment to the 1981 Canada-Alberta agreement on natural gas pricing limited payments by the Commission during the period May 1, 1984 to April 30, 1985 to $75 million.

ALBERTA COST OF SERVICE

Alberta cost of service includes costs and charges relating to the acquisition and movement of natural gas from the point of purchase to the Alberta border. Original buyers that remove natural gas from the Province apply to the Commission each month for determination of Alberta cost of service in respect of gas purchased in the month. The monthly averages of Alberta costs of service determined by the Commission over the last five years are shown in Figure 5.

In 1984, transportation costs represented 47 percent of the total Alberta costs of service while costs of financing take-or-pay payments for gas not taken amounted to 37 percent. Administration costs of the original buyers made up the remaining 16 percent.

The Commission, upon an application or statement of objection by an original buyer or on its own initiative, makes rulings on matters of principle and matters involving categories of costs and charges eligible for inclusion in Alberta cost of service. Rulings on 27 applications and ten statements of objection were issued in 1984. Any cost of service determination made by the Commission may be appealed to the Public Utilities Board for public hearing.

NATURAL GAS MARKETS INCENTIVE PLAN

This program, with effect from April 1, 1984 was developed in response to the June 30, 1983 Canada-Alberta amending agreement and is designed to maintain and expand natural gas sales in eastern Canada. Incentive payments are made by the Commission to Manitoba, Ontario, and Quebec natural gas distributors who, in turn, rebate payments to large industrial and commercial customers whose volumes reach or exceed previously experienced levels.

Payments under the Natural Gas Markets Incentive Plan are funded by a Market Development Levy assessed against gas intended to be removed from Alberta through an Alberta cost of service surcharge. Monthly market development levies assessed in the last quarter of 1984 have ranged from $0.02 to $0.05 per gigajoule. As of December 31, 1984 $2.0 million had been paid to distributors under the plan.

Continuation of the program beyond its initial year depends on continuation of the provisions of the Canada-Alberta pricing agreement which limits Alberta's liability to the federal government under the Market Development Incentive Payments program.

FIGURE 4
DESTINATION OF NATURAL GAS SOLD BY THE COMMISSION

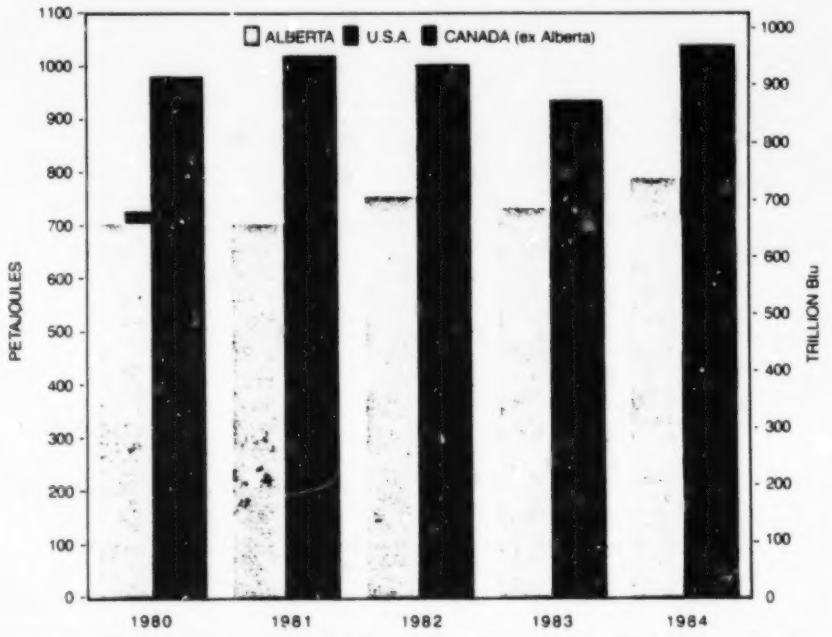
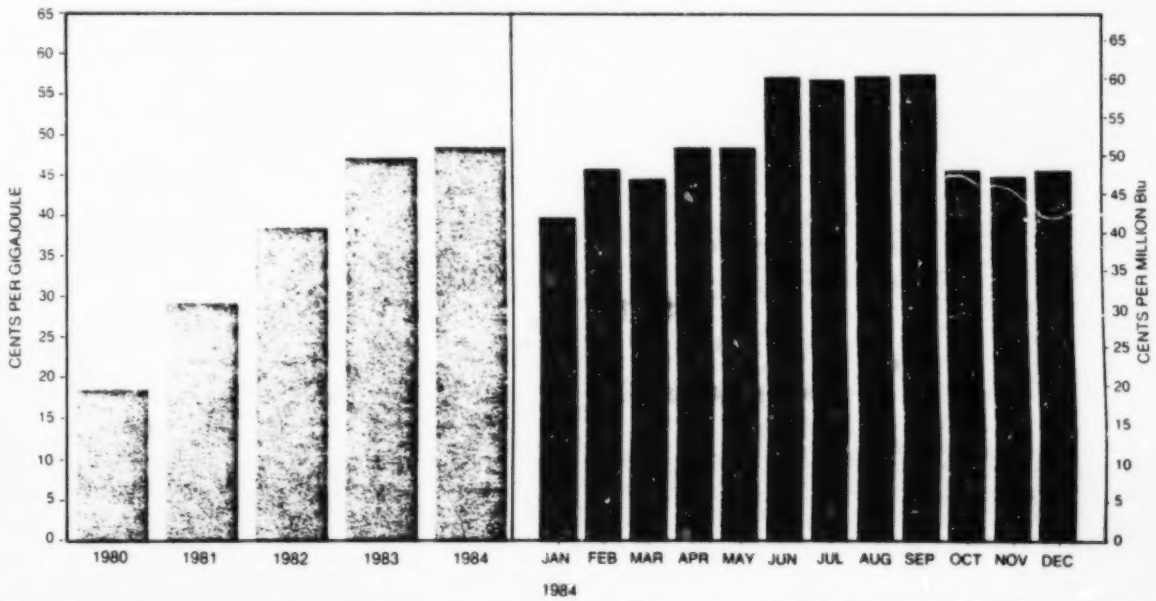


FIGURE 5
AVERAGE OF ALBERTA COSTS OF SERVICE



OTHER ACTIVITIES

REGULATORY ANALYSIS

The Commission intervened in several regulatory proceedings before the National Energy Board and continued to monitor regulatory developments in both Canada and the United States.

Argument in the B.C. Hydro electric power export hearing was presented before the National Energy Board and an intervention for monitoring purposes was registered in the Manitoba Hydro electric power export hearing. The Commission was concerned with the potential erosion of natural gas markets in the United States served by Alberta gas as a result of competition from less expensive hydroelectric exports. The Commission advocated that exports of electric power be evaluated on pricing criteria which does not discriminate against competing natural gas exports.

The Commission intervened in the TransCanada PipeLines Limited generic proceeding relating to method of regulation. Evidence was filed in which the Commission put forth its position on toll regulation and the allocation of costs resulting from facilities expansion of the TransCanada PipeLines Limited system. The Commission maintained that, once facilities are justified, the cost of service relating to expansion of the TransCanada PipeLines Limited system should be rolled-in with existing facilities and allocated between domestic and export markets on the existing volume distance method. The National Energy Board terminated the hearing in February of 1985 but indicated it may recommence once a new Canada-Alberta natural gas pricing agreement has been executed.

An active role was taken during the year in toll hearings for TransCanada PipeLines Limited, Trans Quebec and Maritimes Pipelines Inc. and Foothills Pipelines (Yukon) Ltd. Concerns in these hearings were the establishment of reasonable tolls. In the case of Foothills Pipelines (Yukon) Ltd., the Commission took the position that costs relating to the proposed Alaska Natural Gas Transmission System main line should not be assessed against Alberta producers by allocation to the Prebuild section.

The Commission cross-examined witnesses and presented argument in a generic proceeding into the method of regulating Westcoast Transmission Company Limited. The purpose of the intervention was to ensure the equitable allocation of costs of service to Alberta gas volumes flowing through the Westcoast Transmission system for export to the United States.

SPECIAL PROJECTS

Many of the Commission's activities focused on the objective of achieving the deregulation of petroleum pricing and marketing, and a more market-sensitive environment for natural gas pricing and marketing.

Pursuant to the June 30, 1983 amendment of the Canada-Alberta agreement, the Province of Alberta set up a task force to find ways of maintaining and expanding natural gas sales to large industrial consumers in Eastern Canada. The Commission participated in this task force and was assigned the responsibility for the administration of the resulting Natural Gas Markets Incentive Plan.

The Commission also participated in the Federal/Provincial Task Force on Gas Export Pricing, set up to investigate how market-sensitive pricing for gas exports could be implemented. Subsequent to the task force's report, a new federal policy was announced which provided for market sensitive pricing of gas exports as of November 1, 1984. Following this announcement, the Commission evaluated and took a position on each of the new and amended contracts and licenses brought before the National Energy Board for approval under the new export policy.

In November, 1984 the Alberta government announced a program to permit Alberta's ethylene petrochemical industry to bridge the gap from regulated to negotiated pricing for its natural-gas-based feedstocks. The Commission was charged with the administration of this program.

SYNCRUDE PROJECT

At the direction of the Government of Alberta, the Commission markets the Province's share of synthetic oil production from the Syncrude Canada Limited project. The province has a 16.74 percent equity participation in the project and a 50 percent share of deemed net profits in lieu of royalty. In 1984 the net profits share was taken as production in kind. The Commission marketed approximately 21 percent of the total five million cubic metres of synthetic oil produced by the project.

In addition to the Commission's functions, a member of the Commission is the Alberta royalty negotiator with respect to synthetic oil produced by the project. This involves establishment of the value of synthetic oil to be used as a factor in determining net profits. At year end this value was $259.82 per cubic metre at the plant gate, including compensation of $71.65 per cubic metre paid by the federal government to reflect international prices.

WORLD SCENE

INTERNATIONAL

Petroleum demand (excluding centrally planned economies [CPE's]) grew by 1.0 percent to 46.2 million barrels per day. Much of this growth, which was concentrated in the first half of the year, resulted from the coal miners' strike in the United Kingdom. During the fourth quarter, petroleum demand was below that of the same period in 1983.

The steady rise in the value of the U.S. dollar contributed to the weakness in petroleum demand outside the United States. In Europe, by January 1984 the dollar's appreciation had erased OPEC's March 1983 price reduction of $5.00 U.S. per barrel. The remainder of the year saw petroleum import prices rise seven percent due to changes in the relative value of currencies.

World petroleum production, including net exports by CPE's, grew by 3.1 percent, with virtually all this increase coming from non-OPEC sources. Figure 6 shows OPEC's supply share of world petroleum demand. OPEC's production level was 18.4 million barrels per day, essentially the same as in 1983.

Proven petroleum reserves grew by five percent to an estimated 699 billion barrels, with most of the increase concentrated in Kuwait and Saudi Arabia. The life index for world reserves also increased to 35 years.

Petroleum prices (see Figure 7) were relatively stable in international spot markets through June 1984, in part because of concern over attacks on tankers in the Persian Gulf in the late spring as well as growth in petroleum demand. However, during the summer downward pressure on prices began to emerge and an increase in demand for heavy fuel oil led to narrower price differentials between light and heavy crude oils.

After a series of meetings in late 1984 OPEC lowered the price of light crude by about $1.00 U.S. per barrel while increasing the price of heavy crude by $0.50 U.S. per barrel.

Uncertainty in the world petroleum market and a large deliverability surplus created downward pressure on prices in international natural gas markets. In the United States, a surplus of natural gas supply has affected markets for a number of years, but not until 1984 did supply surpluses emerge in Europe.

World natural gas production increased 6.7 percent to 55.6 tcf. Most of this increase was in the Soviet Union and the North Sea. Production in non CPE countries increased 5.4 percent to 33.1 tcf. The Soviet Union became the largest natural gas producer in the world.

Proven world reserves of natural gas increased 6.2 percent to 3,400 tcf. Proven reserves in non CPE countries increased by 8.6 percent to 1,904 tcf, representing 55 years supply. This increase was well above the average of 3.5 percent per year during the past decade. Most of the increase in these reserves was the result of successful exploration in the North Sea and the Middle East.

LNG has increased its contribution to international energy supply and in 1984 several new players entered the market, including Brunei, Saudi Arabia, and Malaysia. Japanese LNG markets are being served largely by southeast Asia (87%), the Middle East (7%), and the United States (4%). The proposed Canadian LNG project, which is intended to serve this market, will thus face strong competition from many sources, including a large new project in Australia.

World coal demand outside CPE's increased by an estimated five percent reflecting a large increase in United States consumption.

Nuclear power provided five percent of total 1984 energy consumption excluding that of the CPE's.

FIGURE 6
WORLD CRUDE OIL SUPPLY & DEMAND
(excluding communist countries)

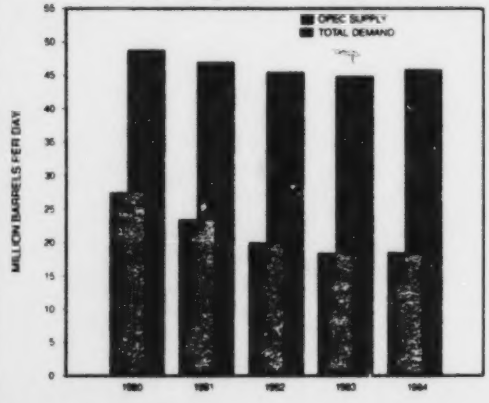
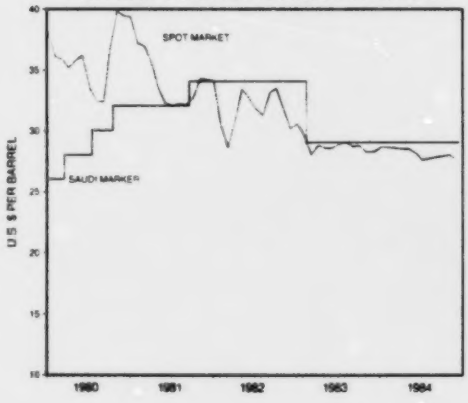


FIGURE 7
COMPARISON OF SPOT AND TERM PRICES
FOR SAUDI ARABIAN MARKER CRUDE



UNITED STATES

Primary energy consumption rose by 4.5 percent, thereby reversing the downward trend of the previous four years. The recovery in energy demand was driven by a buoyant economy which grew in real terms by almost seven percent. Energy consumption by source since 1980 is illustrated in Table 5.

Petroleum demand increased by three percent to 15.7 million barrels per day. Most of this increase occurred in middle distillate and aviation fuel. The demand for residual fuel oil declined for the seventh consecutive year due mainly to lower consumption by the electric utility sector. These changes caused refiners to produce a surplus of gasoline, which put downward pressure on gasoline and light crude oil prices. United States refiners reacted both by importing fifteen percent more petroleum products at discounted prices and by upgrading or closing inefficient refineries. Refining capacity dropped three percent to 15.4 million barrels per day thereby increasing industry utilization to 76 percent from 73 percent in the previous year.

Weakness in the petroleum market created increased uncertainty in domestic crude oil prices. As early as January 1984 some independent refiners began posting field prices for West Texas Intermediate crude at $0.50 U.S. per barrel below the $30.00 U.S. per barrel level of the major integrated refiners. By year end, posted prices had fallen to the $28.50 - $29.00 U.S. per barrel range in response to the OPEC price reductions. Spot market prices remained substantially below posted prices for most of the year (see Figure 8).

In contrast to petroleum product imports, crude oil imports increased only 2.0 percent to 3.4 million barrels per day.

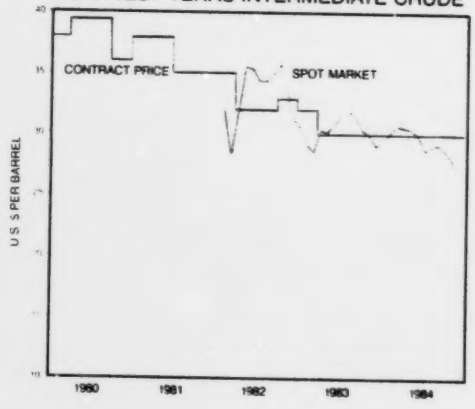
The persistence of a significant deliverability surplus and regulatory transition significantly altered the structure of the natural gas industry. In December 1983, the Federal Energy Regulatory Commission reported a 4.0 tcf natural gas deliverability surplus and although 1984 consumption increased 4.8 percent to 17.6 tcf estimates of the surplus at the end of 1984 were still between 2.0 and 3.0 tcf. This surplus was large enough to create strong downward pressure on prices.

The natural gas industry underwent a major regulatory transition in 1984. The regulatory framework became more flexible and encouraged competition. These developments allowed natural gas prices to fall and promoted increased activity on the spot market.

TABLE 5
UNITED STATES
PRIMARY ENERGY CONSUMPTION
(QUADRILLION BTU's)

	Petro-leum	Natural Gas (Dry)	Coal	Electricity Hydro	Nuclear	Other	Total
1980	34.2	20.4	15.4	3.1	2.7	0.1	75.9
1981	31.9	19.9	15.9	3.1	3.0	0.1	73.9
1982	30.2	18.5	15.3	3.6	3.1	0.1	70.6
1983	30.1	17.4	15.9	3.9	3.2	0.1	70.5
1984	31.0	18.0	17.2	3.8	3.5	0.2	73.7

FIGURE 8
COMPARISON OF SPOT AND TERM PRICES
FOR WEST TEXAS INTERMEDIATE CRUDE



Electricity sales increased four percent in 1984, which was the largest yearly gain since 1977. While electricity demand continues to reflect changes in economic activity, it no longer grows twice as fast as the gross national product, its long term historic trend.

Demand for coal increased by seven percent. Coal use in the electric-utility sector, which accounted for 82 percent of all coal burned, grew about six percent to reach its highest level ever. The United States continues to be the world's largest coal consumer and producer.

While nuclear power supplied nearly five percent of total primary energy consumption, the nuclear industry continues to be plagued by waste disposal problems, cost overruns, regulatory difficulties and negative public opinion.

CANADA

Canada's energy policies came under significant review with the election of a new federal government in late 1984. This review led to a new era of decontrolled crude oil prices commencing June 1, 1985 and a statement of intent to install more market-responsive natural gas prices by November 1985.

In Canadian energy markets, conservation and substitution for petroleum products continued. Despite economic growth of 4.8 percent, petroleum demand registered a small decline. Primary energy consumption by source since 1980, as a percentage of total consumption, illustrates the growth of coal and electricity demand (see Table 6).

Canadian crude oil exports rose to their highest level since 1975. Light crude oil exports averaged 13,500 cubic metres per day, while heavy crude exports averaged 35,000 cubic metres per day. The price of Canadian light crude oil into the United States was as much as $14.15 U.S. per cubic metre below both the posted and spot market prices of United States crude oil. This discount was a result of the wide fluctuation of Canadian crude oil volumes available, the regulatory process involved in exporting Canadian crude oil and increased transfer of discounted petroleum products into the United States midwest.

Petroleum product exports also increased by ten percent to an average of 22,300 cubic metres per day. Product exporters were aided by the decline in the relative value of the Canadian dollar and changes in the regulated pricing system for crude oil which essentially subsidized these export sales.

Canadian crude imports remained at 1983 levels, averaging 38,900 cubic metres per day.

Alberta supplied 70 percent of Canada's crude oil needs, or 163,700 cubic metres per day. This level was virtually the same as 1983, with reductions in shipments to Quebec and the Atlantic provinces offset by an increase in sales to Alberta refineries. Figure 9 illustrates the disposition of Alberta petroleum in its major markets.

Alberta crude production, including a significant expansion of heavy oil and bitumen production, rose by nearly five percent to an average of 205,000 cubic metres per day. Synthetic crude oil output fell by 17 percent to an average of 21,200 cubic metres per day, due to production interruptions in January and in the August through December period. Despite the pipeline constraint the average volume of shut-in crude decreased from 8,000 cubic metres per day in 1983 to 800 cubic metres per day in 1984. By year end, heavy oil production had strained the capacity of the major trunkline moving crude oil east of Alberta.

Despite the fact that some refining capacity was closed, the modernization of the remaining plants and the opening of Shell Canada Resources Limited's Scotford refinery resulted in a 1,590 cubic metres per day increase of refining capacity to 320,000 cubic metres per day. Total refinery production rose by only 1.2 percent, and capacity utilization remained low by historical standards, at 73 percent, down marginally from the 74 percent figure of 1983.

Canadian natural gas production increased 8.8% to 75.0 billion cubic metres. Alberta production was 62.0 billion cubic metres, an increase of 9.6 percent and accounted for 83 percent of this total.

Canada announced a new natural gas export pricing policy in July 1984 in response to regulatory transition in the United States and export sales consistently below National Energy Board licenced volumes. This allowed exporters to negotiate market-responsive prices. Most of the major long term contracts were renegotiated and approved by the Canadian government in time for the 1984-85 contract year. Under the new pricing regime, the average export price fell from $142.79 to $116.28 U.S. per thousand cubic metres. Alberta natural gas export volumes increased by almost six percent in 1984.

Natural gas remained price competitive with other energy forms in eastern Canadian markets. Substitution for crude oil gained momentum due to natural gas being priced more aggressively to capture a larger share of the industrial and commercial markets. Surplus electricity, particularly in Quebec, provided natural gas with stiff competition, especially in the large industrial sector. The Alberta government responded to this competition with the introduction of the Natural Gas Market Incentive Program, designed to retain and increase natural gas sales to large industrial users east of Alberta. In addition, the Alberta border price was frozen throughout 1984. As a result, natural gas enhanced its competitive position and captured an increasing share of the industrial and commercial markets in eastern Canada.

Domestic sales of Alberta gas were 42.5 billion cubic metres, up 10.4 percent from 1983. Quebec natural gas sales continued to increase as transmission and distribution systems expanded, and totalled 4.2 billion cubic metres, an increase of 16 percent. Colder weather, industrial inventory replenishment and increased economic activity in the steel and automotive industries combined to increase natural gas sales in Ontario to 19.2 billion cubic metres, 13 percent over 1983 levels.

Sales of Alberta natural gas to Manitoba, British Columbia and Saskatchewan totalled 3.5 billion cubic metres, a decrease of five percent from 1983 levels. This decrease resulted from Saskatchewan's continued development of indigenous supply.

Natural gas sales within Alberta increased to 15.1 billion cubic metres, 9.9 percent over 1983 levels. Residential and commercial markets have seen little or no expansion; gains can be attributed to increased industrial activity primarily in the petrochemical industry.

Well completions in Canada rose by 30 percent primarily as a result of increases in drilling in Saskatchewan and Alberta. Oil well completions increased 36 percent and natural gas well completions rose 9 percent.

Proven reserves of crude oil rose five percent to 7.1 billion cubic metres. This increase was approximately four times total 1984 consumption. Proven reserves of natural gas rose an estimated five percent.

Canadian consumption of electricity increased by 7.2 percent to 386 million megawatt hours and net exports increased by 9.7 percent to 39 million megawatt hours.

Canada remained a net exporter of coal as exports increased to 20.5 million tonnes and imports increased to 18.7 million tonnes, up from 15.5 million and 12.7 million tonnes, respectively.

TABLE 6
CANADIAN PRIMARY ENERGY CONSUMPTION (PERCENTAGE)

	Coal	Crude Oil	Natural Gas	Electricity	Other
1980	11.7	52.8	22.4	11.7	1.4
1981	12.4	50.8	22.4	12.6	1.8
1982	14.1	46.9	24.2	13.2	1.6
1983	14.8	44.8	24.7	13.8	1.9
1984	16.1	42.4	25.1	13.9	2.5

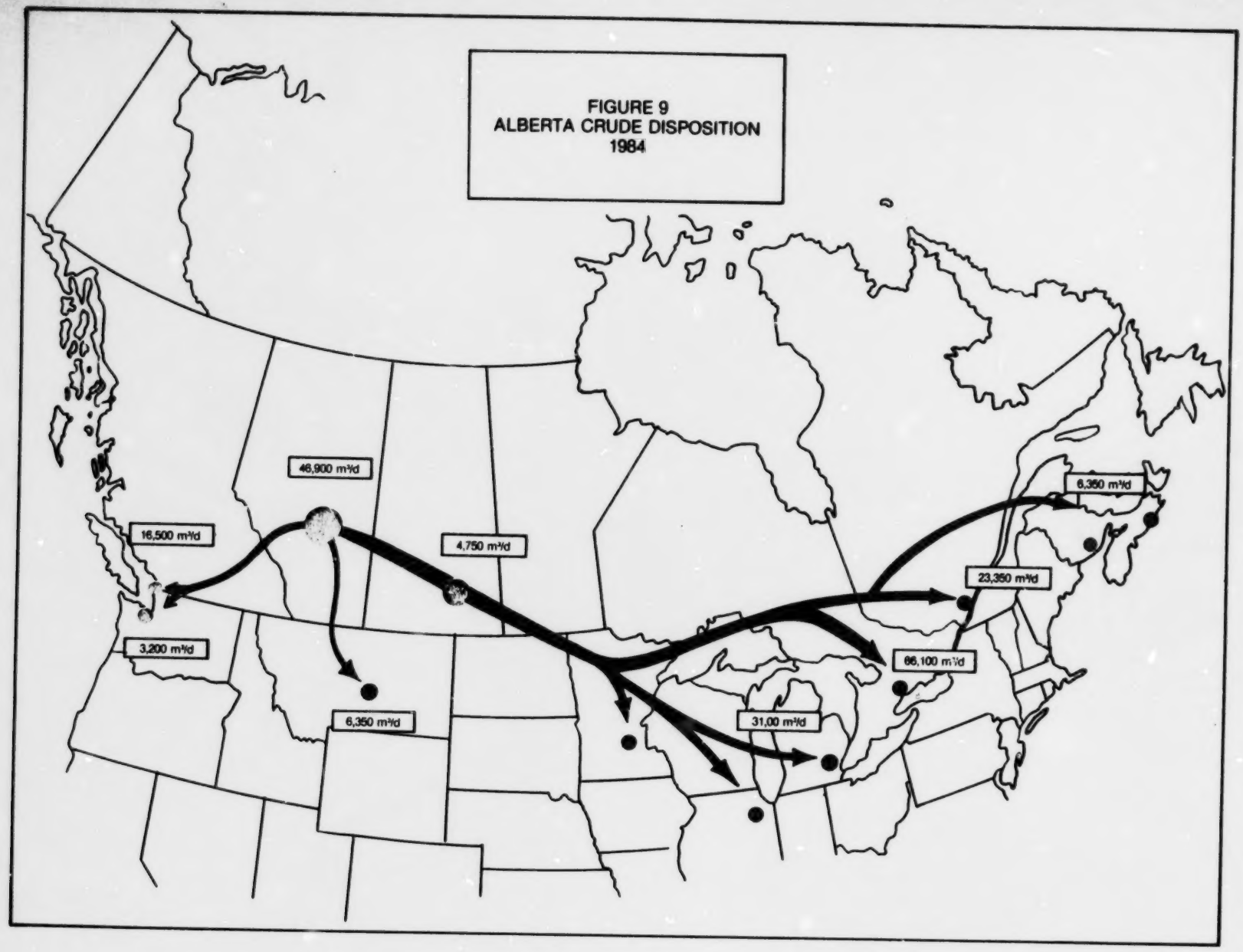


FIGURE 9
ALBERTA CRUDE DISPOSITION
1984
46,900 m³/d
16,500 m³/d
4,750 m³/d
6,350 m³/d
23,350 m³/d
3,200 m³/d
66,100 m³/d
6,350 m³/d
31,00 m³/d

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1984 and the statements of revenue and expenditure for the Operating Fund and the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1984 and the results of its operations for the year then ended in accordance with the disclosed basis of accounting, considered appropriate in the circumstances, as described in Note 2 to the financial statements applied on a basis consistent with that of the preceding year.

F.C.A.
Auditor General

Edmonton, Alberta
October 4, 1985

Alberta PETROLEUM MARKETING COMMISSION

BALANCE SHEET

As At December 31, 1984

ASSETS

	1984	1983
OPERATING FUND		
Current		
Cash and short-term investments	$ 3,366,339	$ 4,195,897
Accounts receivable	492,720	118,225
	3,859,059	4,314,122
Furniture, equipment and leasehold improvements, at cost (Note 3)	2,278,254	2,257,548
	6,137,313	6,571,670
PETROLEUM MARKETING FUND		
Current		
Cash and short-term investments	34,802,036	19,626,549
Accounts receivable (Note 5)	1,035,618,047	979,705,877
Inventory, at cost	32,780,999	35,084,009
	1,103,201,082	1,034,416,435
	$ 1,109,338,395	$ 1,040,988,105

The accompanying notes are part of these financial statements.

LIABILITIES

	1984	1983
OPERATING FUND		
Current		
Accounts payable	$ 210,420	$ 645,186
Deferred contributions	3,648,639	3,668,936
	3,859,059	4,314,122
Capital surplus	2,278,254	2,257,548
	6,137,313	6,571,670
PETROLEUM MARKETING FUND		
Current		
Accounts payable to Crown lessees	641,856,412	609,908,925
Crown royalty payable	313,656,933	300,977,982
Buy/sell, freehold and transportation payable	147,687,737	123,529,528
	1,103,201,082	1,034,416,435
	$ 1,109,338,395	$ 1,040,988,105

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
OPERATING FUND

For the Year Ended December 31, 1984

	1984	1983
Revenue		
Contribution from the Province of Alberta	$ 3,942,609	$ 539,627
Interest ((Note 4)	2,373,395	2,087,559
Gain on sale of inventory	—	3,839,701
Income from export marketing	18,030	216,333
	6,334,034	6,683,220
Expenditure		
Salaries and employee benefits	4,036,121	3,744,293
Rental of premises (Note 8)	1,023,560	1,112,279
Technical studies	366,524	435,208
Computer services	209,832	166,471
Travel	205,552	254,642
Printing and office supplies	151,782	125,615
Personnel consultants	68,384	83,098
Rental of office equipment	66,405	65,565
Publications and periodicals	57,666	52,344
Postage and freight	34,416	32,944
Furniture and equipment	28,409	539,501
Telephone	27,145	27,615
Advertising	22,681	5,939
Leasehold improvements	15,527	20,194
Building and equipment maintenance	4,618	1,231
Insurance	3,331	5,426
Miscellaneous	12,081	10,855
	6,334,034	6,683,220
Excess of revenue over expenditure	$ —	$ —

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
PETROLEUM MARKETING FUND

For the Year Ended December 31, 1984

	1984	1983
Revenue (Note 6)		
Sale of petroleum, pentanes plus and bitumen	$11,124,633,908	$ 9,983,676,452
New oil reference price supplement	1,486,685,391	756,556,216
Special old oil price supplement	6,078,584	23,108,604
	12,617,397,883	10,763,341,272
Expenditure		
Purchases	1,547,298,787	1.161,768,548
Transportation	170,846,842	142,700,220
	1,718,145,629	1,304,468,768
Crown lessees' share	7,572,992,695	6,457,893,924
Crown royalty share	3,326,259,559	3,000,978,580
	12,617,397,883	10,763,341,272
Excess of revenue over expenditure	$ —	$ —

Alberta PETROLEUM MARKETING COMMISSION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1984

Note 1 Authority

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980.

Note 2 Significant Accounting Policies

General

These financial statements have been prepared in accordance with generally accepted accounting principles except that no depreciation or amortization has been provided on fixed assets as purchases are charged to operating fund expenditure in the year of acquisition. Furniture, equipment and leasehold improvements are shown on the balance sheet at original cost with the offsetting credit to capital surplus.

Deferred Contributions

The unexpended portion of contributions received from the Province of Alberta has been deferred to cover operating costs for the period to March 31, 1985. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure

The Natural Gas Pricing Agreement Act Fund and Natural Gas Pricing Agreement Market Development Fund are administered by the Alberta Petroleum Marketing Commission pursuant to the Natural Gas Pricing Agreement Act. The expenditure related to the administration of these Funds is reflected in the statement of revenue and expenditure - Operating Fund.

Inventory

Inventory represents the Crown royalty share of petroleum and pentanes plus remaining in the feeder pipelines at December 31. Gains and losses as a result of price changes are included as revenue of the Operating Fund.

Reliance on Information From the Department of Energy and Natural Resources

The Department of Energy and Natural Resources provides the Commission with royalty and production information which is used for determining the royalty share of petroleum deliveries.

Prior Years' Adjustments

Payment adjustments resulting from corrections to prior years' deliveries are recorded in the year they are processed. These adjustments arise primarily from operator reported amendments and changes in production information received from the Department of Energy and Natural Resources.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Furniture, Equipment and Leasehold Improvements

Changes in furniture, equipment and leasehold improvements were as follows:

	Balance December 31, 1983	Purchases	Disposals	Balance December 31, 1984
Furniture and equipment	$ 1,656,896	$ 28,409	$ 23,230	$ 1,662,075
Leasehold improvements	600,652	15,527	—	616,179
	$ 2,257,548	$ 43,936	$ 23,230	$ 2,278,254

Note 4 Interest

Interest represents amounts earned from account balances and short-term investments of the Petroleum Marketing Fund and the Operating Fund.

Note 5 Petroleum Marketing Fund Accounts Receivable

Petroleum Marketing Fund accounts receivable consist of the following:

	1984	1983
Transactions related to December petroleum deliveries	$ 1,033,384,068	$ 973,912,937
Prior months' accounts, net	2,233,979	5,792,940
	$ 1,035,618,047	$ 979,705,877

Note 6 Revenue - Petroleum Marketing Fund

New Oil Reference Price Supplement Payments

Effective January 1, 1982, pursuant to the Canada-Alberta agreement on energy pricing dated September 1, 1981, oil discovered after December 31, 1980 became eligible for the New Oil Reference Price (NORP). NORP supplement payments were received from the federal government for the difference between the established NORP price and the field price for conventional old oil. The NORP supplement payments were extended to cover pentanes plus and bitumen effective April 1, 1982. (see Note 9)

Special Old Oil Price Supplement Payments

Effective July 1, 1982, pursuant to The National Energy Program Update of May 1982, oil discovered from April 1, 1974 to December 31, 1980 became eligible for the Special Old Oil Price (SOOP). Pentanes plus discovered from January 1, 1974 to December 31, 1980 also became eligible for the SOOP price on July 1, 1982. SOOP supplement payments were received from the federal government for the difference between the established SOOP price and the field price for conventional old oil. This category became eligible for NORP prices, effective July 1, 1983.

Note 7 Syncrude Project

The Commission, through an agency agreement, markets the Province of Alberta's share of synthetic oil from the Syncrude Project. Acting by appointment from the Minister of Energy and Natural Resources, it also markets the Crown royalty share of synthetic oil. These activities are not reflected in the Commission's financial statements. However, marketing and administrative costs associated with these activities are included in the statement of revenue and expenditure - Operating Fund.

Note 8 Lease Commitment

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360 plus occupancy costs.

Note 9 Subsequent Events

Pursuant to the Energy Pricing and Taxation Understanding entered into by the governments of Alberta and Canada on March 27, 1985, the Commission's activities changed effective June 1, 1985. Although still responsible for marketing Crown royalty oil, the Commission ceased to act as the exclusive agent for marketing of the Crown lessees' share and became a competitor with other buyers and sellers of oil. At this time the NORP program was also discontinued and crude oil prices deregulated.

Note 10 Approval of Financial Statements

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1984 and the statement of revenue and expenditure for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1984 and the results of its operations for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

F.C.A.
Auditor General

Edmonton, Alberta
October 4, 1985

NATURAL GAS PRICING AGREEMENT ACT FUND

BALANCE SHEET

As At December 31, 1984

ASSETS

	1984	1983
Current		
Cash and short-term investments	$ 34,203,514	$ 20,340,220
Accounts receivable (Note 3)	55,609,434	159,663,183
	$ 89,812,948	$180,003,403

LIABILITIES

Current		
Price adjustments payable	$ 68,492,890	$156,053,161
Market development incentive payable (Note 4)	21,320,058	23,950,242
	$ 89,812,948	$180,003,403

The accompanying notes are part of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND

STATEMENT OF REVENUE AND EXPENDITURE

For the Year Ended December 31, 1984

	1984	1983
Revenue		
Natural gas sales	$ 6,636,666,517	$ 5,981,221,356
Interest	2,955,385	1,457,629
	6,639,621,902	5,982,678,985
Expenditure		
Natural gas purchases	5,523,298,171	4,549,612,738
Price adjustments	1,040,010,825	1,406,003,534
Market development incentive (Note 4)	76,312,906	27,062,713
	6,639,621,902	5,982,678,985
Excess of revenue over expenditure	$ —	$ —

NATURAL GAS PRICING AGREEMENT ACT FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1984

Note 1 Authority

The Natural Gas Pricing Agreement Act Fund is established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's statement of revenue and expenditure - Operating Fund.

Prior Year's Adjustments

The Natural Gas Pricing Agreement Act permits claimants on the Fund to make or amend claims for price adjustment for a period up to one year after the gas is delivered.

Adjustments for purchases and sales of prior delivery periods are recorded in the financial statements in the year they are processed.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Accounts Receivable

Accounts receivable consist primarily of net proceeds from December natural gas sales.

Note 4 Market Development Incentive Payments

Pursuant to the Canada-Alberta agreement on gas pricing of November 1981, payments out of the Fund are required to be made by the Commission to the Government of Canada for the purpose of facilitating the expansion of markets in provinces east of Alberta for gas produced in Alberta.

In accordance with an amendment to this agreement, a limitation of $75,000,000 was placed on the aggregate amounts of market development incentive payments for which the Commission was liable in relation to the period from May 1, 1984 to April 30, 1985.

Note 5 Approval of Financial Statements

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the statement of receipts, payments and fund balance of the Natural Gas Pricing Agreement Market Development Fund for the eight months ended December 31, 1984. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, this financial statement presents the balance of the Fund as at December 31, 1984 and the receipts collected and payments made for the period then ended.

F.C.A.
Auditor General

Edmonton, Alberta
October 4, 1985

NATURAL GAS PRICING AGREEMENT MARKET DEVELOPMENT FUND

STATEMENT OF RECEIPTS, PAYMENTS AND FUND BALANCE

For The Eight Months Ended December 31, 1984

	1984
Receipts	
Market development levies	$ 9,160,685
Interest	24,003
	9,184,688
Payments	
Retention incentives	788,404
Development incentives	1,255,572
	2,043,976
Excess of receipts over payments	7,140,712
Fund balance at May 1, 1984	—
Fund balance at December 31, 1984 (Note 3)	$ 7,140,712

The accompanying notes are part of this financial statement.

NATURAL GAS PRICING AGREEMENT MARKET DEVELOPMENT FUND

NOTES TO THE FINANCIAL STATEMENT

December 31, 1984

Note 1 Authority

The Natural Gas Pricing Agreement Market Development Fund is established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended, and came into operation on May 1, 1984.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's statement of revenue and expenditure - Operating Fund.

Reliance on Distributor Submissions

In accordance with Section 20 (6) of the Natural Gas Pricing Agreement Act, the Commission has entered into agreements with natural gas distributors in Manitoba, Ontario and Quebec for the purpose of providing incentives for the retention and development of natural gas markets by those distributors.

The agreements provide for retention and development incentive payments by the Commission to distributors who pass these payments to their customers, based on natural gas consumption at eligible facilities. In accordance, with these agreements, the Commission relies on certified submissions received from distributors as the basis for payments made from the Fund.

The agreements with distributors provide for an audit report to be furnished to the Commission within six months following the end of each plan year. The first plan year runs from May 1, 1984 to April 30, 1985 and any adjustments arising from these audits will be recognized in the year the reports are received by the Commission.

Note 3 Fund Balance

The Fund balance is represented by cash and short-term investments.

Note 4 Comparative Figures

As this is the first reporting period of the Fund, comparative figures have not been provided.

Note 5 Approval of Financial Statement

This financial statement was approved by the Commission.

COMMISSION DIRECTORY

(as at date of publication)

COMMISSION MEMBERS

Dale A. Lucas
Chairman

David L. Willis
Vice Chairman

James E. MacKenzie
Member

GENERAL COUNSEL AND SECRETARY

W. Murray Smith

AUDITOR

Edwin K. Adams

FINANCE AND ADMINISTRATION

Garth K. Palmer
General Manager

T.N. Ritchie Fons
Comptroller

William G. Henderson
Manager, Financial Accounting - Petroleum

Betty A. Lilly
Manager, Office Services

Brian R. Zapfe
Manager, Financial Accounting - Natural Gas & Payroll

CRUDE OIL SUPPLY AND DISTRIBUTION

Robert McLean
General Manager

Gary E. Baerg
Manager, Crude Oil Supply

Victoria A. Kidd
Manager, Crude Oil Marketing

Donald M. Olineck
Manager, Crude Oil Supply Accounting

NATURAL GAS

Vernon M. Thomas
General Manager

William A. McKain
Manager, Cost of Service

Wayne O. Presber
Manager, Regulatory Analysis

Adrian Smith
Manager, Natural Gas Sales & Claims

INFORMATION SERVICES

Richard W. Tovell
General Manager

Sam K. Leung
Manager, Computer Services

Basil R. Wheeler
Manager, Systems Development

ENGINEERING AND PLANNING

Raymond S. Dunwald
General Manager

Ritchie S. Fairbairn
Manager, Market Analysis & Planning - Natural Gas

Robert F. McDonald
Manager, Market Analysis & Planning - Petroleum